TECHNICAL REVIEW DOCUMENT For OPERATING PERMIT 040PAD0270 to be issued to:

Blue Spruce Energy Center, LLC
Adams County
Source ID 0011354

Prepared by Jacqueline Joyce November 2004 Revised February, April, August and October 2005

I. Purpose:

This document establishes the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, the Public and other interested parties. Conclusions made in this report are based on information provided by the applicant in the Title V application submitted February 13, 2004, comments on the draft permit and technical review document received on March 17 and May 18, 2005, various telephone conversations and e-mail correspondence with the source and review of Division files.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised Construction Permit.

II. Source Description

The Blue Spruce Energy Center, LLC consists of two simple cycle combustions turbines used to generate electric power under Standard Industrial Classification 4911. The combustion turbines are primarily fueled by natural gas and are designed to burn distillate fuel oil as a back-up fuel source. The gross electrical power output of each combustion turbine is 151.9 MW (at 5600 ft and 20 °F). The combustion turbines also have the capability of injecting steam, water, air or some combination thereof, for the generation of additional power. This process is referred to as power augmentation.

The facility is located at 1751 N. Powhaton Road (on the north side of Interstate 70 at the intersection of Smith Road and Powhaton Road). The facility is located within the Denver metro area, which is classified as attainment/maintenance for particulate matter less than 10 microns (PM₁₀), 1-hr ozone (volatile organic compounds) and carbon monoxide and attainment for all other criteria pollutants. Under that classification, all SIP-approved requirements for PM₁₀, VOC and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(I) of the Federal Clean Air Act. In addition, the entire 1-hr ozone/VOC attainment/maintenance area is also part of the 8-hr Ozone Control Area as defined in Colorado Regulation No. 7, Section II.A.16.

There are no affected states within 50 miles of the facility. In addition, Rocky Mountain National Park, a federal class I area is within 100 km of this facility.

This facility is considered to be a minor stationary source (Potential to Emit < 250 tons/yr). Facility wide emissions are as follows:

Pollutant	Potential to Emit (tons/yr)	Actual Emissions (tons/yr)	
PM	36.2	10.64	
PM ₁₀	36.2	10.64	
NO _X	94.5	30.37	
SO ₂	27.3	0.71	
CO	54.3	0.78	
VOC	4.3	1.43	
HAPS	3.1	no data avail.	

Potential to emit (PTE) is based on permitted emission limits. HAP potential to emit is based on the information provided in the notes to the construction permit. Actual emissions are based on information in the Division's September 22, 2004 inspection report for the period of September 1, 2003 through August 31, 2004.

The Title V permit application did not indicate whether the facility was subject to the risk management plan provisions in section 112(r) of the Act. However, in the construction permit application, the source indicated that they did not anticipate storing or processing any listed chemicals above the threshold levels that would trigger applicability.

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. NO_X emissions from the turbines, when burning natural gas are controlled by DLN combustion systems. DLN combustion systems are not considered control devices as defined in 40 CFR Part 64 §64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since DLN combustion systems are considered inherent process equipment. However, when burning distillate fuel, the turbines utilize water injection to reduce NO_X emissions. Water injection is considered a control device as defined in 40 CFR Part 64 §64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV. Therefore, the

CAM requirements apply to the turbines, when distillate oil is used as fuel. For small pollutant specific emissions units a CAM plan is not required until renewal (40 CFR Part 64 § 64.5(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV), therefore, CAM does not apply to these turbines at this time.

III. Emission Sources:

The following sources are specifically regulated under terms and conditions of the Operating Permit for this Site.

<u>Units CT-01 and CT-02</u> – Two (2) General Electric, Model No. 7FA (PG 7241), Combustion Turbines, Serial Nos. 298203 and 298204. Natural Gas is the primary fuel for these turbines, with distillate oil used as a back-up fuel. Each turbine is rated at 1,495 mmBtu/hr when burning natural gas (HHV) and 1,620 mmBtu/hr when burning distillate oil (HHV) at an ambient temperature of 59 $^{\circ}$ F, relative humidity of 60% and 100% load. Each turbine drives a generator capable of a gross electrical power output of 151.9 MW (at 5600 ft and 20 $^{\circ}$ F). Each turbine is equipped with dry Low NO_X combustion systems and water injection (when firing distillate oil) to reduce NO_X emissions.

Discussion:

1. Applicable Requirements - These units were issued Colorado Construction Permit 01AD0575 as an initial approval on January 4, 2002. A revised construction permit was issued on June 27, 2005, as an initial approval modification. Both units commenced operation in February 2003. According to the Division's data-base, a self-certification was submitted on August 6, 2003, but a final approval permit has not been issued. Under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect. The appropriate provisions of the initial approval construction permit have been directly incorporated into this Title V operating permit.

The turbines are subject to the following applicable requirements from Colorado Construction Permit 01AD0575 (initial approval, modification no. 1, issued June 27, 2005):

• Prevention of Significant Deterioration (PSD) requirements shall apply at such time that this source becomes major solely by virtue of relaxation in any permit condition (condition 2).

This requirement will not be included in the Title V operating permit since no actual requirements apply, unless certain modifications to the permit conditions for these turbines are made. Although this requirement will not be included in the permit, future modifications that cause the turbines to become major, for purposes of PSD review, by virtue of relaxation of any of these permit conditions will result in the application of PSD review.

• The turbines are subject to the following processing limits (condition 3)

Burning natural gas only
 5,570 mmSCF/yr

Burning distillate fuel only: 8,476 mGal/yr

At the time this construction permit was issued, the source was a synthetic minor source for major non-attainment area new source review, with relatively high permitted emissions of NO_X (a precursor to PM_{10}). Likely the Division included fuel consumption limits that change according to the turbines' operating mode in order to assure compliance with the synthetic minor NO_X limit. However, NO_X and CO emissions from the turbines are monitored with a continuous emission monitoring system; therefore, adjusting the fuel consumption limit with the turbines' operating mode really isn't necessary to insure compliance with the NO_X and CO emission limits. Therefore, the Division has removed the requirements requiring the source to adjust their fuel consumption limits for different turbine operating modes. Note that compliance with the PM, PM_{10} , VOC and SO_2 emission limits are based on emission factors and fuel consumption. Therefore, the source may find it necessary to increase the permitted emissions for these pollutants in the event that the turbines consume quantities of fuel close to the permitted limits.

 Total facility emissions of air pollutants shall not exceed the following limits (condition 4):

0	Particulate Matter	36.20 tons/yr
0	Particulate Matter less than 10 µm	36.20 tons/yr
0	Nitrogen Oxides	94.5 tons/yr
0	Carbon Monoxide	54.30 tons/yr
0	Sulfur Dioxide	27.30 tons/yr
0	Volatile Organic Compounds	4.30 tons/yr

In addition, the permit indicates that these emission limits apply to the facility, not necessarily just to the turbines. Since the area in which the facility is located is no longer non-attainment for any pollutants, the major stationary source threshold is now 250 tons/yr and the water bath heater is no longer subject to APEN reporting requirements (at requested fuel consumption rate NO_X emissions are below 2 tons/yr). Therefore, while the facility is still a synthetic minor source for purposes of major stationary source permitting requirements, it is not necessary to permit or track emissions from insignificant activities with the higher threshold. Therefore, the above emission limitations will be included in the permit but will only apply to the turbines.

 Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 6 and Colorado Regulation No. 1, Sections II.a.1 & 4).

Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term "normal operations" applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered "normal operation". Therefore, the language in the permit will not specify "normal operation". The 30% opacity requirement will be written to include all the specific operational activities identified in Reg 1.

RACT requirements apply as follows (condition 7).

<u>Nitrogen Oxides</u> the following emissions limits (on an hourly average) apply to each turbine:

- When burning natural gas, without power augmentation: 9 ppmvd at 15% O₂
- When burning natural gas, with power augmentation: 12 ppmvd at 15%
 O₂
- o When burning distillate fuel oil: 42 ppmvd at 15% O₂
- During periods of combustion tuning and testing and fuel switching, 200 ppmvd at 15% O₂,
- Use of the above limit for combustion tuning and testing shall not exceed
 100 hrs/yr for both turbines combined.

Note that the control technology that was determined to be RACT (dry low NO_X combustion technology when burning natural gas and water injection when burning distillate oil) was not identified in the construction permit but will be identified in the operating permit.

<u>Carbon Monoxide:</u> the following emission limits (on an hourly average) apply to each turbine:

- When burning natural gas: 15 ppmvd at 15% O₂
- When burning distillate fuel oil: 20 ppmvd at 15% O₂
- During periods of combustion tuning and testing and fuel switching,
 1,000 ppmvd at 15% O₂,
- Use of the above limit for combustion tuning and testing shall not exceed 100 hrs/yr for both turbines combined.

Note that as discussed above, the control technology (good combustion practices) was not identified in the construction permit but will be identified in the operating permit.

<u>Particulate matter < 10 μ m:</u> The following emission limits (no averaging time provided) apply to each turbine:

- When burning natural gas: 0.015 lb/mmBtu
- When burning distillate fuel oil: 0.045 lbs/mmBtu

Since no averaging time was provided, the Division considers that compliance with the RACT limits is based on the required performance test, which is the average of three (3) 1-hour tests. Based on a review of the file, it is not clear what the basis of the RACT limits are. The RACT limits appear to exceed the emission rates on which the annual permit limits are based on (i.e. lb/hr emission rates divided by the heat input rate). Note that performance tests were conducted February 16 to 28, March 17 to 27 and May 6, 2003 and the results of the test indicate that the turbines comply with the RACT emission limitations (Unit 1 – natural gas PM = 0.010 lb/mmBtu, distillate fuel oil PM = 0.009 lb/mmBtu and Unit 2 – natural gas PM = 0.006 lb/mmBtu, distillate fuel oil PM = 0.014 lb/mmBtu).

In addition, as discussed above, the control technology (fuel restriction - pipeline quality natural gas and distillate fuel oil with sulfur content not to exceed 0.05% by weight) was not identified in the construction permit but will be identified in the operating permit.

<u>Volatile Organic Compounds:</u> The construction permit did not include RACT requirements for VOC although such requirements apply in accordance with Colorado Regulation No. 7, Section II.C.2. The Division considers that RACT is fuel restrictions (pipeline quality natural gas and distillate fuel oil with a sulfur content less than 0.05 % by weight) and good combustion practices.

The permit indicates that the RACT limits do not apply during startup and shutdown but that emissions during those periods must be included for determination of compliance with the annual emission limits. The construction permit did not define startup and shutdown but included time limitations. The Division considers that it is more appropriate to determine startup and shutdown in terms of operating conditions or parameters rather than time. Following discussions between the Division and the source, the source requested startup and shutdown limits in terms of operating conditions in their May 18, 2005 comments on the draft permit. Those startup and shutdown definitions have been included in the renewal permit.

- The combustion turbines are subject to Regulation No. 6, New Source Performance Standards, Part A, as follows (condition 8):
 - Federal Register Regulations Adopted by Reference, Subpart GG, specifically:
 - NO_X emissions shall not exceed 114 ppmvd at 15% O₂, on a 4-hr rolling average, when burning natural gas, and

- NO_X emissions shall not exceed 100 ppmvd at 15% O₂, on a 4-hr rolling average, when burning distillate fuel oil, and
- SO₂ ≤ 150 ppmvd at 15% oxygen OR sulfur content in the fuel shall not exceed 0.8 percent by weight

Although not specifically identified in the construction permit, the source is subject to monitoring requirements on the nitrogen and sulfur content of the fuel and for water injection the source is required to install and operate a monitoring system to monitor the fuel consumption and ratio of water to fuel, continuously.

It is not clear whether the source submitted an alternative monitoring plan to EPA for approval. However, NSPS GG was revised on July 8, 2004 (Federal Register, Volume 69, No. 130) to provide additional monitoring options for NO_X emissions and nitrogen and sulfur content monitoring that have previously been approved by EPA. The revisions allow use of a NO_X CEMS in lieu of continuously monitoring the fuel consumption and ratio of water or steam to fuel. In addition the revisions specify that for sources that do not take credit for fuel-bound nitrogen in their NO_X emission limitations that no fuel sampling for nitrogen is required. Finally, for sampling fuel for the sulfur content, the revisions specify that no fuel sampling is required for natural gas and that for fuel oil the sampling frequency and methods in 40 CFR Part 75 Appendix D may be used. The Division will include the appropriate provisions from the revised NSPS GG in the permit or streamline as appropriate.

- Part A, Subpart A (condition 8)
 - Good practices (§ 60.11(d))
 - Circumvention (§ 60.12)

Note that a more extensive list of requirements from 40 CFR Part 60 Subpart A was included in the construction permit. However, these requirements, if still applicable, will be included in the permit as periodic monitoring or under the continuous emission monitoring requirements and will not be specifically identified as requirements under the NSPS general provisions.

- The turbines are subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part B – Specific Facilities and Sources, Non-Federal NSPS, II – Standards of Performance for New Fuel-Burning Equipment, D – Standard for Sulfur Dioxide, 3 – Combustion Turbines (condition 9). These are state-only requirements.
 - SO₂ emissions shall not exceed 0.35 lbs/mmBtu.

Although not specifically identified in the construction permit, the turbines are also subject to the 20% opacity requirement in Section II.C.3.

- For each combustion turbine, a continuous emission monitoring system (CEMS) shall be installed calibrated, certified, maintained and operated to measure and record (condition 10):
 - Hourly average concentrations of NO_X and CO;
 - Hourly average concentration of O₂, percent;
 - Emissions of NO_X, tons/mo, tons per rolling twelve month period;
 - Emissions of CO, tons/mo and tons/rolling 12 month permits;
 - o Fuel flow rate, SCF/hr for gas and gallons per hour for distillate fuel oil
 - Water injection rate and water-to-fuel ratio

QA/QC shall be as per the Division approved procedures.

Because the hourly ppm data are converted to lbs/hr to calculate mass emissions, the Division will include lbs/hr as a parameter to be recorded. In addition, in their comments on the draft permit the source indicated that the rolling twelve month totals were not recorded on the data acquisition and handling system (DAHS) for the CEMS. Therefore, the twelve month rolling totals will not be identified as values recorded on the CEMS. Finally, the Division will also require that the data acquisition and handling system of the CEMS record operating mode (i.e. startup, shutdown or standard operation) and load (MW).

The hourly fuel flow rate required by the construction permit will be identified as a separate requirement and not included as a CEMS requirement.

It is not clear if the Division has approved a CEMS plan for this source; however, since the source is exempt from RACT requirements during startup and shutdown, the CEMS must be capable of excluding only startup and shutdown data for purposes of monitoring compliance with the RACT limits and calculating hourly averages from partial clock hours that occur after startup ends and before shutdown begins. The CEMS shall also be capable of calculating mass emissions (lbs/hr) during periods of startup and shutdown for use in monitoring compliance with the annual emissions limits.

APEN reporting requirements (condition 11).

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

Although not specifically identified in Colorado Construction Permit 01AD0575, the turbines are subject to the following applicable requirements:

 Particulate matter emissions, from each turbine, shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III.A.1.c)

- Sulfur dioxide emissions, from each turbine, shall not exceed 0.35 lbs/mmBtu, on a 3-hour rolling average (Reg 1, Section VI.B.4.c.(ii) and VI.B.2)
- Each turbine is subject to the Acid Rain requirements as follows:
 - Allocated SO₂ allowances are listed in 40 CFR Part 73.10(b), however, since these are new units, no allowances were allocated. SO₂ allowances must be obtained per 40 CFR Part 73 to cover SO₂ emissions for the particular calendar year.
 - There are no NO_X emission limitations since these units are not coalfired boilers.
 - Acid rain permitting requirements per 40 CFR Part 72.
 - Continuous emission monitoring requirements per 40 CFR Part 75.
 - This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

Streamlining of Applicable Requirements

Opacity

The turbines are subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. The turbines are also subject to the state-only Reg 6, Part B 20% opacity requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other at all times, all three opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency.

<u>SO</u>₂

The turbines are subject to the Regulation No. 1 and Regulation No. 6, Part B SO₂ requirements. The Regulation No. 1 and No. 6, Part B SO₂ standards are the same, 0.35 lbs/mmBtu. The Regulation No. 6, Part B requirement is a state-only requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the excess emission reports. Specifically,

EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B SO₂ requirements do not apply during periods of startup, shutdown and malfunction. Therefore, the Regulation No. 1 SO₂ requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

The turbines are also subject to the Acid Rain SO_2 requirements. Sources subject to Acid Rain must hold adequate SO_2 allowances to cover annual emissions of SO_2 (1 allowance = 1 ton per year of SO_2) for a given unit in a given year. The number of allowances can increase or decrease for a unit depending on allowance availability. Allowances are obtained through EPA, other units operated by the utility or the allowance trading market and compliance information is submitted (electronically) to EPA. Pursuant to Regulation No. 3, Part C, Section V.C.1.b, if a federal requirement is more stringent than an Acid Rain requirement, both the Reg 1 and the Acid Rain SO_2 requirements shall be incorporated into the permit and shall be federally enforceable. For these reasons, the Acid Rain SO_2 requirements have not been streamlined out of the permit. The source will have to demonstrate compliance with both the Acid Rain SO_2 requirements and the Reg 1 SO_2 standard. Note that the Acid Rain SO_2 allowances appear only in Section III (Acid Rain Requirements) of the permit.

<u>NO</u>_X

The NSPS Subpart GG and RACT concentration limits are in the same units and the NSPS GG averaging time is less stringent (4 hrs vs 1 hr), so they can be compared for purposes of streamlining. The RACT concentration limits are applicable at all times, except during periods of startup and shutdown. In their May 18, 2005 revised comments on the permit, the source requested a higher RACT limit for periods of combustion tuning and testing and fuel switching.

The Division considers that the NSPS Subpart GG requirements are not applicable during periods of startup, shutdown and malfunction (as discussed in the SO_2 streamlining section above). Although the revisions to NSPS GG require reporting of excess NO_X emissions during periods of startup and shutdown (§ 60.334(j)), the preamble to the rule (July 8, 2004 Federal Register, pg 41354, 1st column, last paragraph) states that "the final rule does not use the term "deviation"." In addition, the preamble goes on to say that EPA recognizes that "even for well-operated units with efficient NO_X emission controls, excess emission "spikes" during periods of startup and shutdown are inevitable" and that "excess emission data may be used to determine

whether a facility's operation and maintenance procedures are consistent with § 60.11(d)." The preamble language appears to confirm that the NSPS GG NO_X limits do not apply during periods of startup and shutdown.

The RACT limits are more stringent than the NSPS GG limits during all periods except during periods of combustion tuning and testing and fuel switching. During the limited periods of combustion tuning and testing, the NSPS GG limits appear to be more stringent than the RACT limits; however, the NSPS GG limits are based on a-4-hr average, rather than a 1-hr average. Therefore, the Division cannot determine whether the NSPS GG limit or the RACT limits are more stringent during periods of combustion tuning and testing and fuel switching. Since the Division cannot determine that one NO $_{\rm X}$ limit is more stringent than the other at all times, both the RACT and NSPS NO $_{\rm X}$ limits are included in the operating permit. See the attached grid for a clarified view on the NO $_{\rm X}$ requirements and their relative stringency, based on a 1-hour average.

Monitoring Requirements

These units are subject to several types of monitoring requirements. The construction permit requires that the stacks be equipped with continuous emission monitoring systems (CEMS) to monitor and record NO_X and CO emissions and the construction permit requires that the QA/QC requirements meet the Division requirements. This unit is also subject to the Acid Rain requirements and as such is required to monitor emissions in accordance with the requirements in 40 CFR Part 75. In addition, under the revisions to NSPS Subpart GG, the source may install a NO_X CEMS that meets the requirements of 40 CFR Part 75.

Since the source has installed Part 75 NO_X (and diluent) CEMS, the permit will specify that the NO_X (and diluent) CEMS must meet the requirements in 40 CFR Part 75. Since the construction permit states that the CEMS will meet the Division-approved procedures, the conditions in the operating permit are Division-approved procedures and no streamlining is necessary. In addition, the requirement in the construction permit to continuously measure the water injection rate and the fuel-to-water ratio will also be streamlined from the permit since NO_X emissions will be measured with the CEMS. Note that the revisions to NSPS GG allow sources with NO_X CEMS to use the CEMS in lieu of measuring the water injection rate and the fuel-to-water ratio.

Since the revisions to NSPS GG allow sources that have installed NO_X CEMS under Part 75 to use those CEMS for compliance, no streamlining is required for the NSPS CEMS requirements. However, in their May 18, 2005 comments on the draft permit, the source requested that the Division streamline the Part 60 QA/QC requirements in favor of the Part 75 requirements. Therefore the Division streamlined the Part 60 QA/QC requirements, with respect to the NO_X CEMS, in favor of the Part 75 requirements.

It should be noted that the NSPS GG revisions indicate that no nitrogen sampling is required if credit was not taken for fuel-bound nitrogen in setting the NO_X emission limitations. This was the case for these units. Therefore, since sampling the fuel for the nitrogen content is not required, there are no requirements to streamline.

It should be noted that for the NO_X CEMS general provisions (Condition 2.2.2), the Division included the primary equipment hourly operating requirements from 40 CFR Part 75 § 75.10(d). Since the turbines are not required to have continuous opacity monitoring systems under 40 CFR Part 75, the Division removed the language from § 75.10(d) regarding the continuous opacity monitoring system since it does not apply to these turbines.

Similarly for the CO CEMS general provisions (Condition 2.2.1), the Division included the continuous emission monitoring requirement from 40 CFR Part 60 § 60.13(e) and since the turbines are not required by the NSPS to have continuous opacity monitoring systems, the Division removed language in § 60.13(e) regarding the continuous opacity monitoring systems, since it does not apply to these turbines.

Under the Acid Rain provisions, sources that demonstrate that the gas burned meets the definition of pipeline quality natural gas may use an emission factor to calculate hourly SO₂ emissions, as allowed by 40 CFR Part 75 Appendix D. The NSPS GG revisions specify that no fuel sampling is required if natural gas is used as fuel, since these turbines burn pipeline quality natural gas, which has a lower sulfur content then natural gas, the methods to demonstrate that natural gas is used as fuel will be streamlined in favor of the Part 75 pipeline quality natural gas requirement.

Similarly under the Acid Rain provisions, units that burn fuel oil may use the provisions in 40 CFR Part 75 Appendix D for monitoring SO₂ emissions. Appendix D provides sampling requirements (i.e. frequency and method) for units burning fuel and as discussed previously, use of the fuel oil sampling requirements from 40 CFR Part 75 Appendix D have been approved as an alternative monitoring method for the NSPS GG fuel sampling requirements. Therefore, the sampling requirements for NSPS GG will be streamlined in favor of the Part 75 Appendix D sampling requirements.

2. Emission Factors - Emissions from these turbines are produced during the combustion process, and are dependent upon operating conditions and specific properties of the natural gas being burned. The pollutants of concern are Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Volatile Organic Compounds (VOC) and Particulate Matter (PM and PM_{10}). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted dependent upon the makeup of the fuel and combustion efficiency.

 NO_X and CO emissions shall be determined using the continuous emission monitoring system required by the construction permit. SO_2 emissions shall be determined using monitoring methods required by 40 CFR Part 75, Appendix D.

As indicated in their comments on the draft permit received on May 18, 2005, the source proposed to use the following emission factors to monitor compliance with the emission limits:

	Natural Gas		Distillate Fuel Oil	
Pollutant	Emission Factor (lbs/mmBtu)	Source	Emission Factor (lbs/mmBtu)	Source
PM	0.010	From	0.015	From
PM ₁₀	0.010	performance	0.015	performance
VOC	0.00121	tests conducted February 16-28, March 7 to 27 and May 6, 2003.	3.9 x 10 ⁻⁴	tests conducted February 16-28, March 7 to 27 and May 6, 2003.

The above emission factors are based on the highest test result for either turbine. For the PM and PM_{10} emission factors, the source requested a margin of 10% above the performance test result. The Division agrees that the emission factors are appropriate to use to monitor compliance with the annual VOC annual limitations.

3. Monitoring Plan - The source shall be required to monitor compliance with the PM, PM_{10} and VOC emission limits by monitoring fuel consumption and calculating emissions monthly. Compliance with the fuel consumption limits will be monitored using the fuel flow meters.

The continuous emission monitoring systems shall be used to monitor compliance with the RACT and annual NO_X and CO emission limitations. The monitoring methods required by 40 CFR Part 75, Appendix D shall be used to monitor compliance with the annual SO_2 emission limitation.

As mentioned previously performance tests were conducted on Units 1 and 2 on February 16 to 28, March 17 to 27 and May 6, 2003 and indicated compliance with all emission limitations. The results of most of the tests were well below the emission limitation or the emission rate used to set the annual limitations. However, when burning natural gas for Unit 1, PM₁₀ emissions were approx. 67% of the RACT limits. Therefore, the Division will require that performance tests be conducted within the last 18 months of the permit term in order to monitor compliance with the PM₁₀ limits.

In the absence of credible evidence to the contrary, compliance with the Reg 1 opacity, particulate matter and SO_2 limits shall be presumed provided pipeline quality natural gas is used as fuel. In the absence of credible evidence to the contrary, compliance with the Reg 1 particulate matter and SO_2 limits shall be presumed provided the distillate fuel oil that is used as fuel has a sulfur content of 0.05 % by weight or less. When burning distillate fuel, compliance with the Reg 1 opacity limits shall be monitored by conducting Method 9 visible emission observations.

The sulfur content of the distillate fuel oil shall be monitored by sampling in accordance with the provisions of 40 CFR Part 75, Appendix D.

4. Compliance Status – The source indicated in the Title V permit application that the turbines were in compliance with all applicable requirements.

Unit H001 - Natural Gas-Fired Water Bath Gas Heater, Rated at 9 mmBtu/hr

1. Applicable Requirements – The water bath gas heater was included in Colorado Construction Permit 01AD0575 (initial approval issued on January 4, 2002) and the heater commenced operation with the turbines in February 2004. In both their March 17 and May 18, 2005 comments on the draft permit the source indicated that the water bath gas heater was rated at 5.5 mmBtu/hr, rather than the 9 mmBtu/hr heater. The revised construction permit issued on June 27, 2005 corrected the size of the heater. The water bath gas heater is not categorically exempt from APEN reporting requirements (i.e. is not less than 5 mmBtu/hr and is not used for comfort heating). At the time the initial approval construction permit was issued, the APEN de minimis level for reporting was 1 ton/yr (non-attainment area for PM₁₀, CO and VO, NO_x is a precursor to PM₁₀) and requested NO_x emissions (at 1900 hrs/yr) from the 9 mmBtu/hr heater were 1.3 tpy; therefore a permit was required because the APEN de minimis level was exceeded. Since the area in which the source is located is no longer nonattainment for any criteria pollutants, the APEN reporting level is 2 tons/yr and no construction permit or APEN would be required. Note that based on AP-42 emission factors, CO emissions from the 5.5 mmBtu/hr heater would be below 2 tons/yr even if the heater was operated 8760 hrs/yr. NO_X emissions would be less than 2 tons/yr if the unit were operated less than 7330 hrs/yr. Since the fuel consumption limit for the turbines does not allow the turbines to run for that many hours in a year, NO_X emissions from the heater will not exceed 2 tons/yr.

Although the facility is still a synthetic minor source for purposes of major stationary source permitting, since the threshold is 250 tons/yr, rather than 100 tons/yr, it is not necessary to permit or track emissions from insignificant activities.

Therefore, the water bath heater will be included in the insignificant activity list in Appendix A. Note that any requirements specific to the water bath heater (i.e. the fuel consumption limit in condition 4 of the construction permit) will not be included in the permit.

Unit T004 – 1,200,000 Gallon Distillate Fuel Oil Storage Tank (Above Ground)

The distillate fuel oil storage tank was first placed in service in February 2003 and was addressed in Colorado Construction Permit 01AD0575 (initial approval issued January 4, 2002, initial approval modification issued June 27, 2005). At that time, the storage tank was subject to recordkeeping requirements in 40 CFR Part 60 Subpart Kb. Although emissions from this tank were below APEN de minimis levels, an APEN needed to be filed under the "catch-all" provisions, since the tank was subject to federal NSPS requirements. The source submitted an APEN on February 4, 2002 and the NSPS Kb recordkeeping requirements were included in the initial approval construction permit. Effective October 15, 2003, revisions were made to NSPS Subpart Kb and under these revisions tanks that have a capacity of 39,889 gallons or greater and storing liquids with a maximum true vapor pressure less than 3.5 kPa (approx. 0.5 psia) are exempt from the provisions of 40 CFR Part 60 Subpart Kb. Since the emissions

from the tank are below APEN de minimis levels and since the tank is no longer subject to any federal NSPS requirements, neither a construction permit nor an APEN is required for this tank and the tank can be considered an insignificant activity. The NSPS Kb requirements were not included in the modified initial approval construction permit. Therefore, the tank is included in the Appendix A of the permit as an insignificant activity.

Emergency Fire Water Pump and Emergency Generator

The construction permit (01AD0575) lists equipment at the facility in Attachment A and lists two distillate fuel fired internal combustion engines, one driving an emergency fire water pump (290 hp) and one driving an emergency generator (rated at 500 hp). Attachment A indicates that neither engine is anticipated to operate for more than 100 hrs/yr. It appears that NO_X emissions from these units are not included in the facility-wide emission limit. At any rate, these emission units are not required to submit APENS and are insignificant activities. Although the facility is still a synthetic minor source for purposes of major stationary source permitting, since the threshold is 250 tons/yr, rather than 100 tons/yr, it is not necessary to permit or track emissions from insignificant activities. Therefore, the engines will be included in the insignificant activity list in Appendix A. In their comments on the draft permit received on March 17, 2005, with revised comments received on May 18, 2005, the source indicated that the emergency generator was never installed.

Ozone Early Action Compact Requirements (Reg 7)

The Division entered into an early action compact to delay being re-designated as a non-attainment area for the 8-hour ozone standard. The early action compact requires controls to reduce VOC emissions in the 8-hour ozone control area. The early action compact VOC control requirements have been included in Colorado Regulation No. 7 and those requirements became effective, on a state-only basis, on May 31, 2004. The VOC control requirements apply to oil and gas operations (Colorado Regulation No. 7, Section XII) and stationary internal combustion engines (Colorado Regulation No. 7, Section XVI) located in the 8-hour ozone control area. Since the facility is not involved in oil and gas operations, only the stationary internal combustion engine requirements potentially apply to this facility. The engine requirements apply to natural gas-fire engines rated at 500 hp or greater. The engine associated with this facility is diesel fuel-fired and therefore the engine control requirements do not apply.

IV. Insignificant Activities

The source indicated that the following general categories of insignificant activities at this site include: landscaping and site housekeeping devices < 10 hp, tanks with annual throughput less than 400,000 gal per year (limited contents), and internal combustion engines (limited size and hours of operation). A specific list of insignificant activities was not included in the Title V permit application. However, based on the information in the Title V permit application and in the construction permit, the Division considers that the following insignificant activities are located at this facility:

<u>Units with emissions less than APEN de minimis - criteria pollutants (Reg 3 Part C.II.E.3.a)</u>

Natural gas fired water bath heater, rated at 5.5 mmBtu/hr

Storage tanks with annual throughput less than 400,0000 gal and meeting content specifications (Reg 3, Part C.II.E.3.fff)

Diesel tank for emergency fire water pump (250 gallons, above ground) Distillate fuel oil storage tank (1,200,000 gallons, above ground)

<u>Stationary Internal Combustion Engines - limited size or hours (Reg 3, Part C.II.E.3.xxx.(ii))</u>

Diesel-fired emergency fire water pump (210 hp)

V. Alternative Operating Scenarios

No alternative operating scenarios were requested for this facility.

VI. Permit Shield

Permit Shield for Non-Applicable Requirements

The source indicated that they wanted the permit shield from all Colorado Air Quality Control regulations that were not identified as specifically applicable to the emissions units at their facility on Title V permit application forms 2000-604. No justification was provided for these regulations. The source has the right under Title V of the Clean Air Act Amendments (CAAA) to request the shield for regulations they determine are not applicable to specific equipment at a site in question. However, justification for each non-applicability determination is required. The Title V permit application did not provide a justification for non-applicability determinations, nor was the specific requirement clearly identified. For these reasons, the permit shield was not granted for any non-applicable requirements.

Permit Shield for Streamlined Requirements

These requirements are applicable to the turbines at the Blue Spruce Generating Center; however, alternative monitoring methods have been approved and included in the permit. As discussed previously in this document, under streamlining of monitoring requirements, the Division has included the above requirements, as appropriate in the permit shield for streamlined/subsumed conditions.

The following applicable requirements were streamlined out of the permit and have been included in the permit shield.

- **State-only** 0.35 lbs/mmBtu SO₂ requirement (Reg 6, Part B, Section II.D.3.b), streamlined out since Reg 1 SO₂ requirement is more stringent.
- Monitor sulfur content of fuel (40 CFR Part 60 Subpart GG § 60.334(h)(3) and (i)(1)), streamlined out in favor of the Acid Rain requirements in 40 CFR Part 75 Appendix D for gas or oil-fired units (sulfur sampling).
- Excess emission reporting for the sulfur content of the (40 CFR Part 60 Subpart GG § 60.334(j)(2)), streamlined out in favor of the Acid Rain requirement for pipeline quality natural gas.
- Water injection rate and fuel-to-water ratio (Colorado Construction permit 01AD0575, condition 15) streamlined out, since the NO_X and diluent monitors shall meet the requirements in 40 CFR Part 75.
- CEMS requirements in 40 CFR Part 60 Subpart A § 60.13, Appendix B, Performance Specification 2 and Appendix F, with respect to the NO_X CEMS only, streamlined out in favor of the Part 75 monitoring requirements

V. Acid Rain Requirements

Both turbines are affected units under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78 and as such the source is required to have provisions for the Acid Rain requirements in its Title V permit. Units subject to the Acid Rain requirements are required to hold adequate SO_2 allowances and have NO_X limitations. This facility is not listed under 40 CFR 73.10(b)(2) and therefore must obtain SO_2 allowances as needed. Since these units are not coal-fired boilers, they do not have any NO_X limitations under the Acid Rain Program.

Typically, units subject to the Acid Rain requirements are required to continuously measure and record emissions of SO₂, NO_X (with diluent monitor either CO₂ or O₂) and CO₂ as well as opacity and volumetric flow in accordance with the requirements in 40 CFR Part 75. Since these units meet the definition of gas-fired units in 40 CFR Part 72 §72.2, these units are not required to have a continuous opacity monitoring system and can use an alternate monitoring method (Appendix D), in lieu of installing and operating a continuous emission monitoring system for SO₂.